## 1.9 Measurement Schematics

This section presents the requirements for measurement schematics used for measurement, accounting, and reporting of oil and gas facilities. Measurement schematics are required to ensure measurement, accounting, and reporting compliance and are a visual tool showing the current physical layout of the measurement and reporting facility. Schematics should be regularly reviewed and used by groups such as operations, engineering, and accounting to ensure a common understanding. For the purpose of this directive, process flow diagrams (PFD), piping and instrumentation diagrams, and process and instrumentation diagrams are not considered measurement schematics.

In this section, an asterisk (*) indicates "optional except for MARP schematics."

### Definitions:

**Process flow diagram -** A **PFD** is a diagram commonly used in chemical and process engineering to indicate the general flow of plant processes and equipment, including

- Process piping
- Major bypass and recirculation lines
- Major equipment symbols, names, and identification numbers
- Flow directions
- Control loops that affect operation of the system
- Interconnection with other systems
- System ratings and operational values as minimum, normal, and maximum flow; temperature; and pressure
- Composition of fluids

**Piping and instrumentation diagram**—A schematic diagram showing piping, equipment, and instrumentation connections within process units

**Process and instrumentation diagram**—A family of functional one-line diagrams showing hull, mechanical, and electrical (HM&E) systems, such as piping and cable block diagrams

**Measurement Schematic—**A diagram used to show the physical layout of facilities that traces the normal flow of production from left to right as it moves from wellhead through to sales. A schematic must include items identified in Section 1.9.1, Contents on a schematic.

**Field Flow Diagram—**A line diagram showing the delineation of facilities and the connectivity of wells to compressors, gathering systems, batteries, and/or gas plants. Equipment, vessels, meters, and sample points are typically not shown on field flow diagrams. A field flow diagram contains

- well location by UWI
- producing company
- well type (oil or gas), if a gas system is wet or dry
- compressors complete with LSD
- facility codes
- final destination – battery, plant, etc.

### 1.9.1 Measurement Schematics Requirements

The Operator of Record on the PRA is responsible for the creation, confirmation, and revision of any measurement schematics. The schematics must be used by operations and production accounting to ensure that the reported volumes are in compliance with the ERCB reporting and licensing requirements.

The facility must be delineated on the measurement schematics. For larger facilities, an optional field flow diagram may be used to show facility delineation. For proration facilities with measured flow-lined receipts, that are not considered as continuous tests, the measured streams should be delineated from the prorated test streams. The ERCB may require the operator to show the facility delineation on the measurement schematic if the field flow diagram is submitted in place of the measurement schematic and is deemed to be insufficient (see Appendix 9 for an example).

The measurement schematic can be stored electronically or in hard-copy format. The measurement schematic must be retained at a central location and previous versions must be stored for a minimum of 18 months. Note that other jurisdictions may require a longer retention time.

**Contents on a Schematic**

The following items must form part of the basis of a schematic for measurement, accounting, and reporting purposes.

*General Facility*

1) Registry codes including facility and subtype codes, reporting facility boundary, and facility LSD

2) Title block: Company name, drawing and version numbers, drawing update or no change confirmation date record, and location identifier, which must include at least one of the following:
    - Facility surface location(s)
    - Facility licence field name
    - Area name
    - Updater’s name (not the draftsman)

3) Where each well ties into the facility

4) All connecting lines between the sheets if there is more than one sheet

5) Flow directions for all product flow lines

6) All symbols and legends - symbols must be identified (the operator may come up with its own symbols and legends as long as they are clearly labelled.)

UWIs and LSDs are to be in the format 100/16-06-056-02W5/02 and 16-06-056-02W5 respectively.

Multiple facilities can be on the same page.

*Wells*

Complete bottomhole UWI, surface location, if different, and all surface commingled events.

If downhole commingled, only the reporting event is required. A typical well schematic may be used for multiple wells with the same well measurement configuration.

Wellhead configuration

- Identify energy/fuel source: gas, propane, electric, etc.
- Identify gas lift, plunger lift, on/off control, cycle timer, pump jack – default to FLOW
- VGWL – volumetric gas well liquid for gas wells – default to COND

Include producing, shut-in, water source, and injection/disposal wells.

- Suspended wells: optional to leave on schematic and identify as such
- Fresh water sources, such as lakes and rivers, must be shown

*Well Test, Satellites, and Field Headers*

Indicate which well ties into these facilities

Test separator configuration (2 or 3 phase)

Test and proving taps if required by the ERCB

*Fuel*

- Fuel gas arrow(s) for fuel gas take-off/consumption points, such as wells, satellites, production field headers, or facilities
- Identify if multiple fuels are used and which one is the backup (e.g., wellhead gas and propane)

*Flare and Venting*

- Identify all permanent flare and vent stacks
- Identifying other venting and flaring sources, such as pig traps, is optional

*Flow Lines*

Acid gas, gathering, emulsion, injection, source water, and common tested lines; blowdown lines*.

*Process Equipment*

Include and label all headers, separators, treaters, line heaters, dehydrators, hydrocarbon liquid recovery units, sweetening units, compressors, knockouts, and pumps*.

- Headers - surface location where flow can be split, combined, or redirected
- Normally open valves, such as emergency shutdown valves (ESDs), pressure-control valves (PCVs), and block valves, are not required as they can be considered default flow.
- Pressure safety valves (PSV) are not required.
- Normally closed valves that can change production flow must be added

- For compressors - HP or KW rating unless fuel gas is measured as part of total fuel within a facility. Some cross-border facilities may be required to measure some compressors individually.
- Gas scrubbers may either be optional or required, such as hydrocarbon scrubbers that reduce vent volumes.

*Measurement Points*

Required on a schematic: meters, meter ID*, tank gauges*, weigh scales, sample points for S&W, sample point ID*, and estimated streams

Estimated streams are the ones that do not need to be measured but are required for reporting

- Indicate type of meters and data gathering elements, e.g., vortex, orifice, Coriolis, turbine, charts, local display, or EFM (per symbols and legends)

Accounting and/or ERCB required measurement points are mandatory:

- Receipt points from other facilities or disposition points are required with UWI, LSD, or reporting code (for truck-in receipt points, no originating facility ID is required)
- Non-accounting meters are option; however, if it is in the schematic, it must be identified as non-accounting, such as reference, process, operator use, or internal.

*Storage Tanks and Vessels*

- Oil, emulsion, gas, condensate, plant product, waste, and water storage tanks, caverns, pressurized storage vessels, or other vessels – tank capacity, fluid type
- Identify underground or aboveground tanks (optional)
- Nonreporting chemical storage or pop tanks are not required or identify as reference if present
- If the tanks or vessels are of the same fluid type and size, it can be shown as one tank on the schematic with a multiplier for the number of tanks
- Indicate if the vessel is tied into a VRU or flare system; default to vented
- Ponds* - volume, fluid type

### 1.9.2 Schematic Updates

Changes affecting reporting must be documented at the field level when they occur and communicated to the production accountant within five days after the calendar month-end to facilitate accurate reporting.

- Physical changes, such as wells, piping, or equipment additions or removal, require schematic update
- Temporary changes within the same reporting period do not require schematic update

Updates must be done annually and include

- changes or deletions to existing schematic, or
- no change confirmation to schematic – name and date

**Exceptions**

Below are the simplified requirements for some battery subtypes:

For Heavy Oil/Crude Bitumen Administrative Grouping (subtype 343): The well list is not required to be on the schematic but should state how many wells are in the battery and must be available upon request.

For SE Alberta Shallow Gas Battery (subtypes 363 and 366): The well list is not required to be on the schematic but should state how many wells there are on each branch coming into the battery location and must be available upon request

For Gas Test Battery (subtype 371) and Drilling and Completion Battery (subtype 381): No measurement schematic is required until the well is tied to a production battery and starts producing.

### 1.9.3 Implementation

- No grandfathering
- An initial window of two years from date of implementation
- Operator of record on the PRA is responsible to maintain the accuracy of the schematic
- Suggested implementation process
  - Build schematic for every facility
  - Update to meet requirement
  - Maintain reporting accuracy

### 1.9.4 Schematic Availability

Schematics must be provided by the Operator of Record on the PRA to the following external parties to facilitate compliance with the requirements:

- Facility licensee of the subject facility
- The company that performs the product and residue gas allocation up to the allocation point(s)
- ERCB or other Alberta/cross-border regulatory bodies
- Operator of receipt/disposition points – all reporting measurement points for the facility only

## 1.10 Facility Delineation Requirements

Delineation of lease sites and geographic areas into reporting facilities is based on the measurement, accounting, and reporting rules described in this directive and *Directive 007*. Facility delineation requires accurate information on process flows and measurement points in the field, as well as a sound understanding of the ERCB facility definitions and subtypes outlined in *Directive 007*.

Multiple measurement points and regulatory flexibility can result in more than one way of delineating some facilities; however, the following general guidelines can be used.

- All gas and liquid received into and delivered from a facility must be continuously measured in a single phase.
- Wells and the associated equipment are only linked to and reported under batteries or injection facilities.
  - Crude oil/bitumen wells are linked to and reported under Crude oil /bitumen batteries.
  - Gas wells are linked to and reported under gas batteries.
  - Disposal wells are linked to and reported under disposal facilities.
  - Injection wells are linked and reported under injection facilities.
  - Source water wells may be linked to either a battery or more commonly the injection facility. If there is gas production, then linking to a subtype 902 battery will facilitate gas production reporting.
- Measured and prorated wells should not be linked to the same battery and must be reported under separate reporting codes.
- Except for thermal in situ schemes, facilities that use either regenerative sweetening processes or hydrocarbon liquid recovery processes must be reported as gas plants.

## Facility Delineation Scenarios

The following facility schematics and descriptions will be added to the appropriate sections in *Directive 017* (indicated in blue font) for clarification.

### 1) Gas Groups (PRA Subtype 361) (add to Section 4.2.2.2)

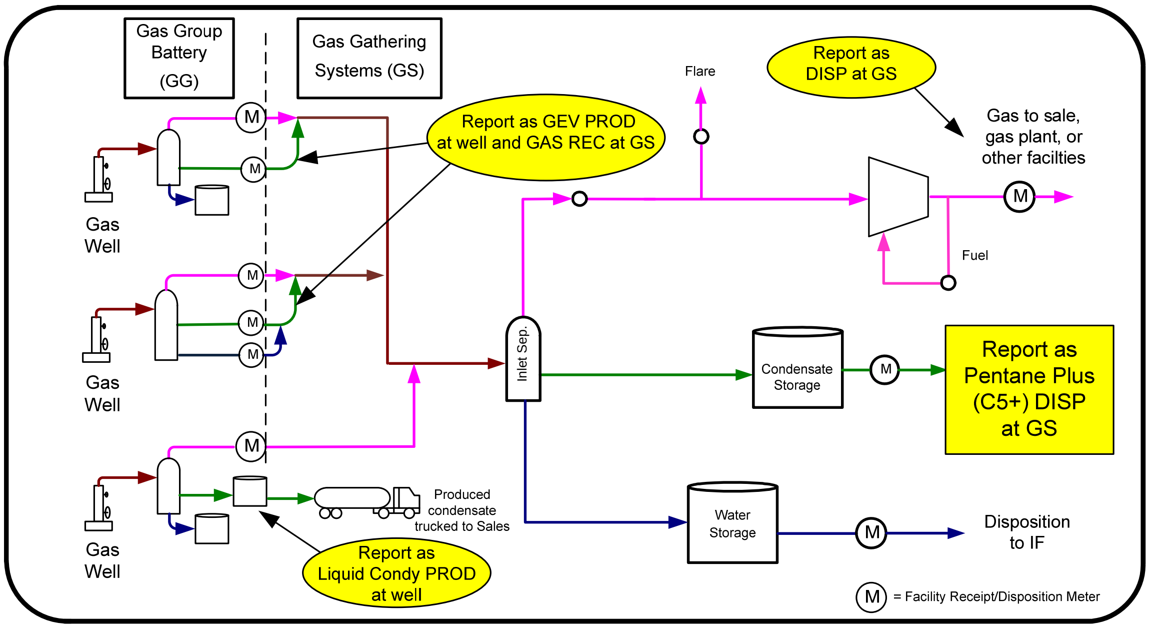



Figure 1. Gas group battery delineation

There is no group measurement point requirement for fluids from the gas group wells, but the wells must deliver to a common facility, normally a GS. Hydrocarbon liquids and/or water may be tanked and disposed of by truck and reported as liquid DISP. Recombined hydrocarbon liquids (reported as gas equivalent volume) and water (reported as liquid water) must be sent to the same common facility as the gas. Multiple gas groups can deliver to the same GS.

If the GS further disposes of the fluids, similar to the above schematic, each fluid type (gas, hydrocarbon liquids, water) disposition must be measured and reported. The GS will also report a metering difference.

When does it make sense to group wells?

Case 1 – 1 operator with 1 reporting entity (1 gas group)

Case 2 – 1 to 4 operators/equity partners with 4 reporting entities (4 SWB) with licensed compressor on one well

Case 3 – 1 or 2 operators with 2 reporting entities (1 SWB and 1 gas group)

Case 4 – 1 or 2 operators with 2 reporting entities (gas groups)

Case 5 – 1 or 2 operators with 2 reporting entities (gas groups) with licensed compressor on one well

See Appendix 10 for case schematics.

**2) Oil Battery with Measured Gas Receipts (Registry Subtype 322 or 342) (add to Section 5.5.1)**

**Scenario 1**

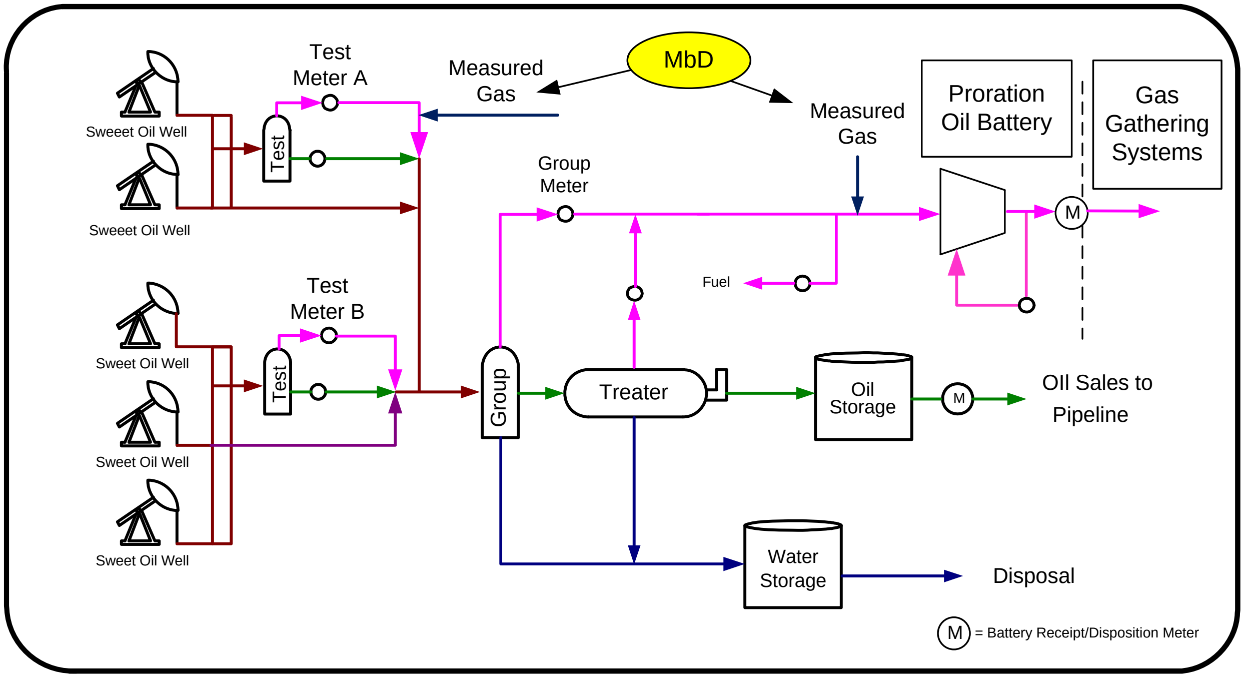



Figure 2. Measured gas coming into oil battery with measurement by difference

**Calculate Actual Battery Gas Production**

Total battery gas disposition is equal to the metered volume after compression. The actual battery gas production is calculated by subtracting the measured gas receipt volumes from the total battery disposition plus fuel, flare, and vent and then prorated to the flow-lined oil wells. The amount of measured gas that can be delivered into the oil battery is limited by the measurement by difference (MbD) percentage in Section 5.5.

**Calculate Battery Oil Production**

If the measured gas streams have condensate, see Section 5.5.1, Table 5.1 and Table 5.2, and Section 14.3 on how to calculate and report condensate shrinkage, flashing, disposition, and receipt.

## Scenario 2

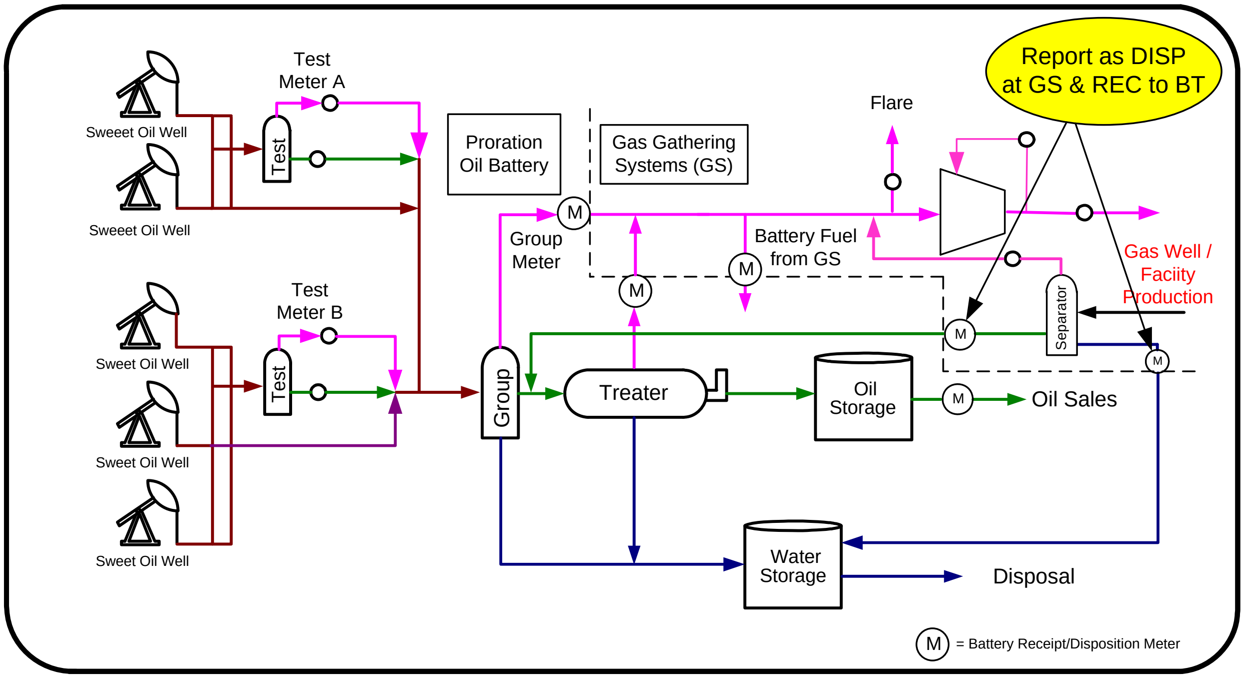



Figure 3. Measured gas battery delivering hydrocarbon liquids and water to an oil battery

### Calculate Actual Oil Battery Gas Production

Total of group and treater gas is prorated back to flow-lined oil wells. Gas meter off separator coming from the measured gas battery is reported as a delivery to the GS. This is a preferred scenario as you are not restricted by gas measurement by difference, but oil measurement by difference still applies.

### Condensate Receipt into Oil Battery

Condensate measured at the gas group separator is reported as a liquid disposition from the gas facility into the oil battery. See Section 5.5.1, Table 5.1 and Table 5.2, and Section 14.3 on how to calculate and report condensate shrinkage, flashing, disposition, and receipt.

### 3) CBM Battery (Registry Subtype 364) (add to Section 4.2.2.4)

**Scenario 1**

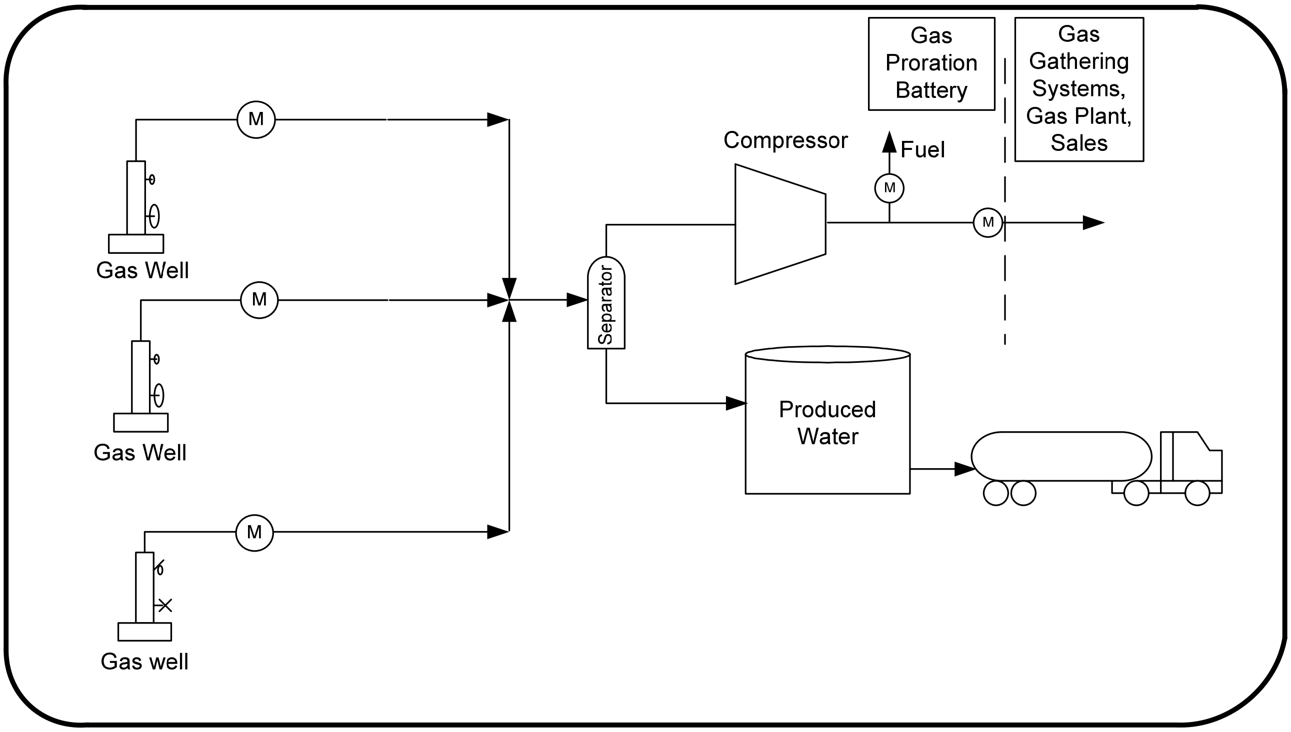



Figure 4. CBM wells with meter at every well and minimal water

**Calculate Actual Battery Water Production**
Water disposition volume with inventory change is to be prorated back to the well level based on a battery-calculated water-gas ratio (WGR) applied to each well.

If water is recovered at a well during swabbing operations, that water is added to the well's production water volume calculated using the WGR for that well. The recovered water must also be added to the battery disposition. The swabbed water can be shipped to a disposal facility or to the battery water tank, but it must not be part of the battery WGR calculation, and it must be netted off if it is put into the battery water tank.

### Calculate Actual Battery Gas Production
Total actual battery gas production is equal to total gas disposition plus fuel, flare, and vent volumes and is prorated back to each well using the gas proration factor based on the well test meter estimated volumes.

**Scenario 2**

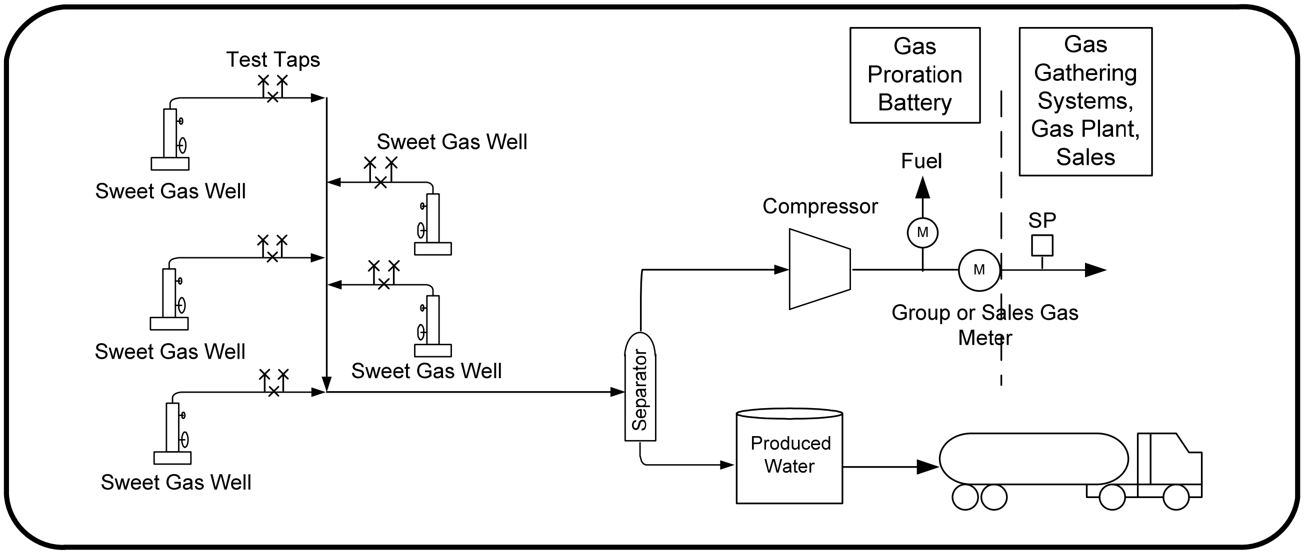



Figure 5. CBM with only test taps at wellhead and minimal water

**Calculate Actual Battery Water Production**

Water volumes to be prorated back to the well level are determined using water dispositions and inventory measurement based on a calculated battery WGR and estimated monthly gas production.

If water is recovered at a well during swabbing operations, that water is added to the produced water volume calculated using the WGR for that well. The recovered water should also be added to the battery disposition. The swabbed water can be shipped to a disposal facility or to the battery water tank, but it must not be part of the battery WGR calculation, and it must be netted off if it is put into the battery water tank.

**Calculate Actual Battery Gas Production**

Total gas production is equal to total gas disposition plus fuel, flare, and vent volumes and is to be prorated back to each well based on its well-test estimated volumes and the gas proration factor.

### 4) Custom Treating, Oil Battery, and Terminal (add to Section 10.2.1)

A terminal is required when there is more than one source of clean oil going through a LACT meter into an oil pipeline. Any oil, water, and gas crossing a facility boundary must be measured. If there is blending of hydrocarbon liquids of densities >40 kg/m$^3$, such as butane blending with the oil before the LACT, the lighter hydrocarbon used for blending must be received and stored at the terminal and the oil production measured before the blending point.

**Scenario 1:** Dedicated tankage for clean crude and produced water for both the crude proration battery and the custom treating battery.

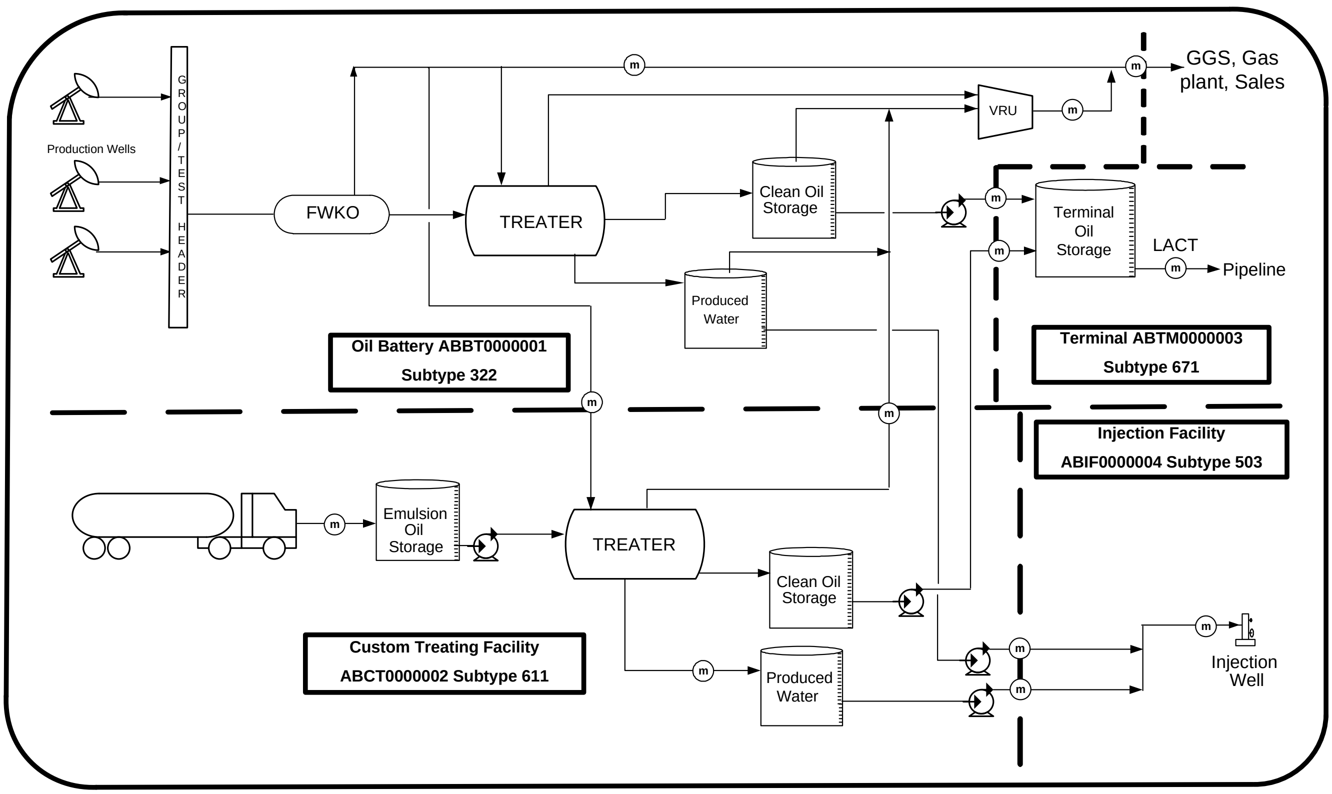



Figure 6. Custom treating, oil battery, and terminal schematic – Scenario 1

**Scenario 2:** Dedicated metering on treaters for water/oil and a shared tank for clean crude and produced water.

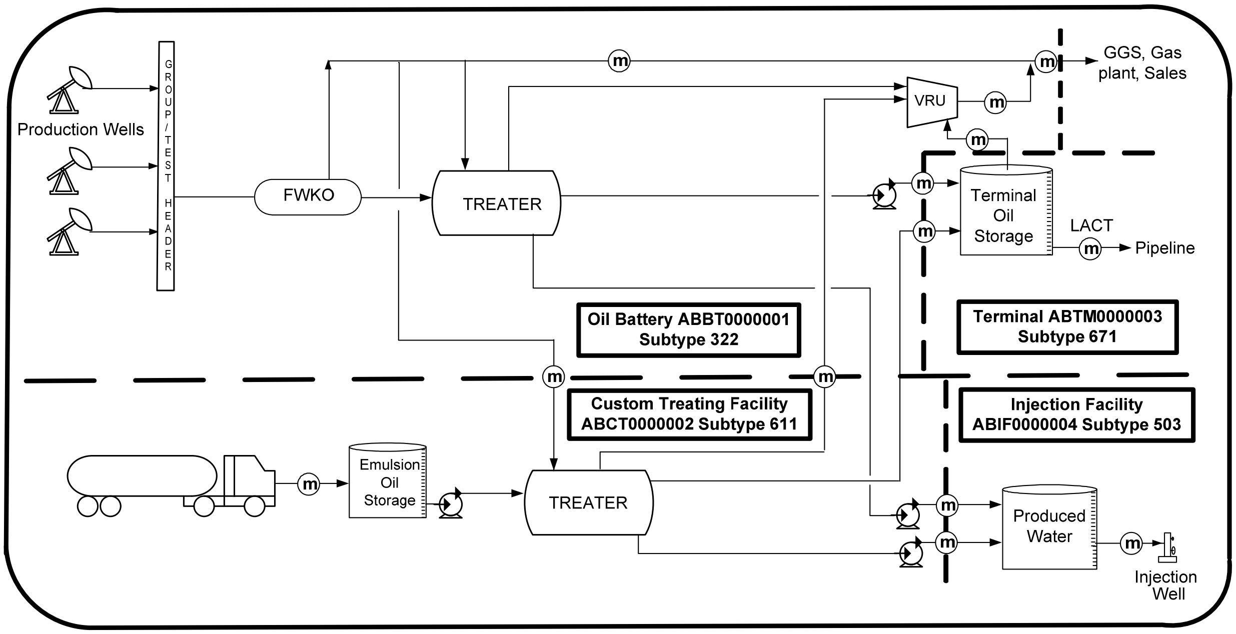



Figure 7. Custom treating, oil battery, and terminal schematic – scenario 2

The main difference between the two scenarios is scenario 1 has dedicated tanks with metering off the tanks, whereas scenario 2 has shared tanks but metering off each treater.

For both scenarios, the transfer of fuel from the proration battery to the custom treating facility provides heat for the custom treater and pressure to help dump the treater to storage tanks. There is also a receipt meter for the gas coming back from the custom treater and terminal to the proration battery.

### 5) Integrated Waste Treatment Including Waste Plant (WP), Custom Treating (CT), Water Disposal (IF), and Terminal (TM) (add to Section 10.2.7)

Integrated oil and water processing and waste facilities are ones with various distinct processing and reporting entities. They are referred to as oilfield waste management facilities (OWMFs).

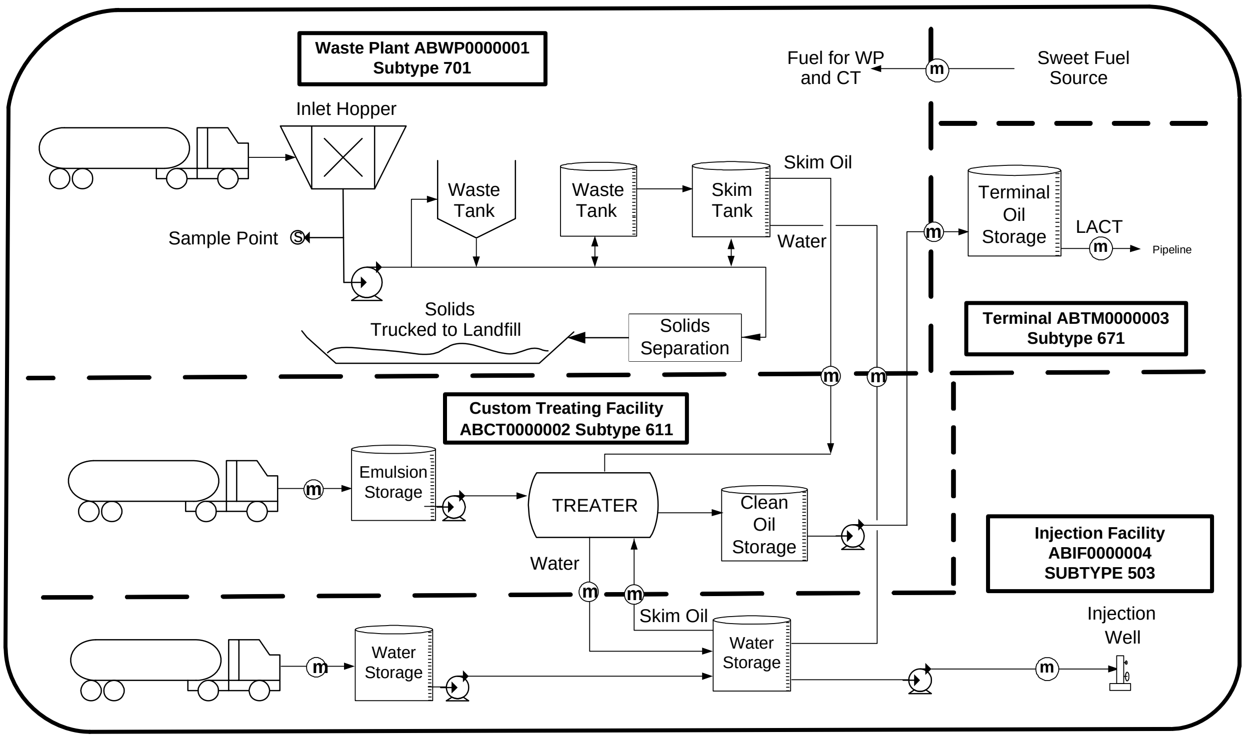



Figure 8. Integrated waste treatment facility delineation

Any fluids transferred between the different reporting facilities within the integrated site must be measured and reported.

Report fuel gas receipt at the WP and fuel gas usage. See Section 5 of *Directive 047: Waste Reporting Requirements for Oilfield Waste Management Facilities* for more details. No fuel gas transfer or fuel use reporting required at the CT in this case.

### 6) Oil Battery Delivering To or Receiving From a Gas Plant on Same Site (add to Section 4.2.2.6)

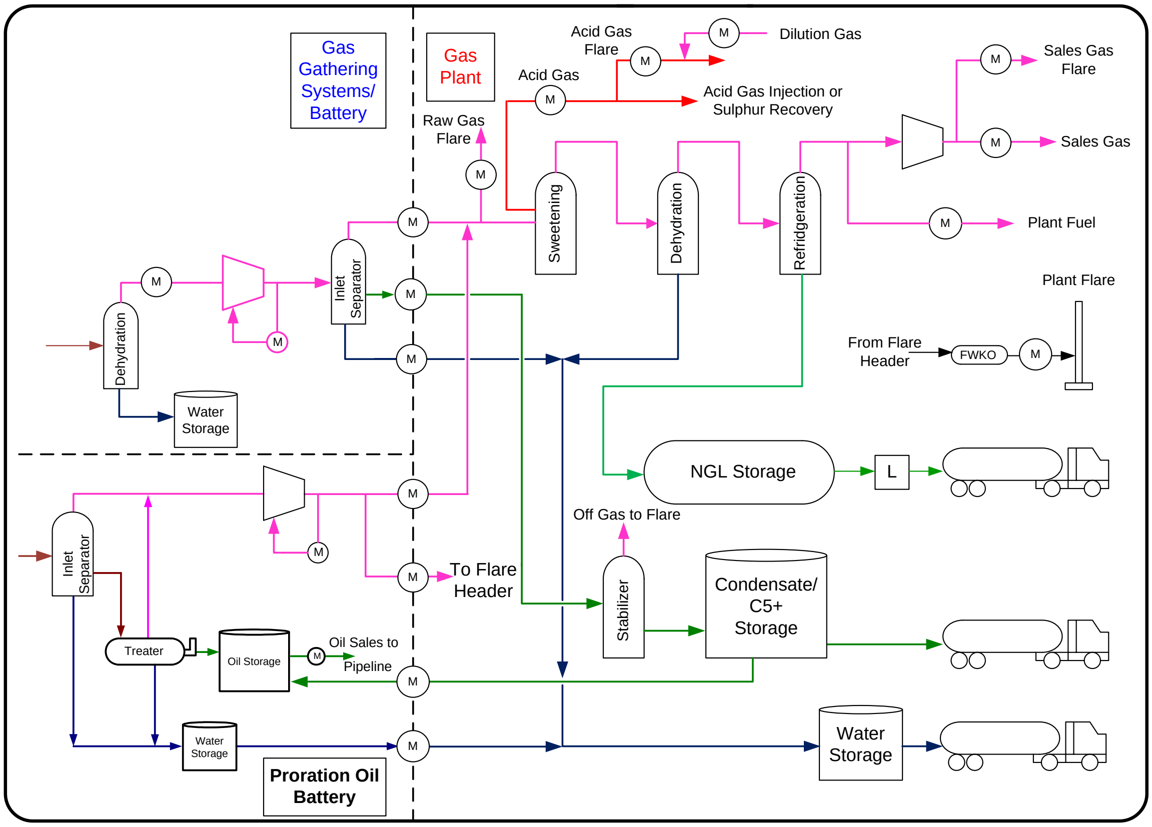



Figure 9. Oil battery delivering to or receiving from a gas plant

Oil battery gas and water sent to a gas plant for further processing or disposition and gas for flaring must be measured and reported as disposition from the oil battery to the gas plant. The gas plant will report the receipts, total flare, and dispositions.

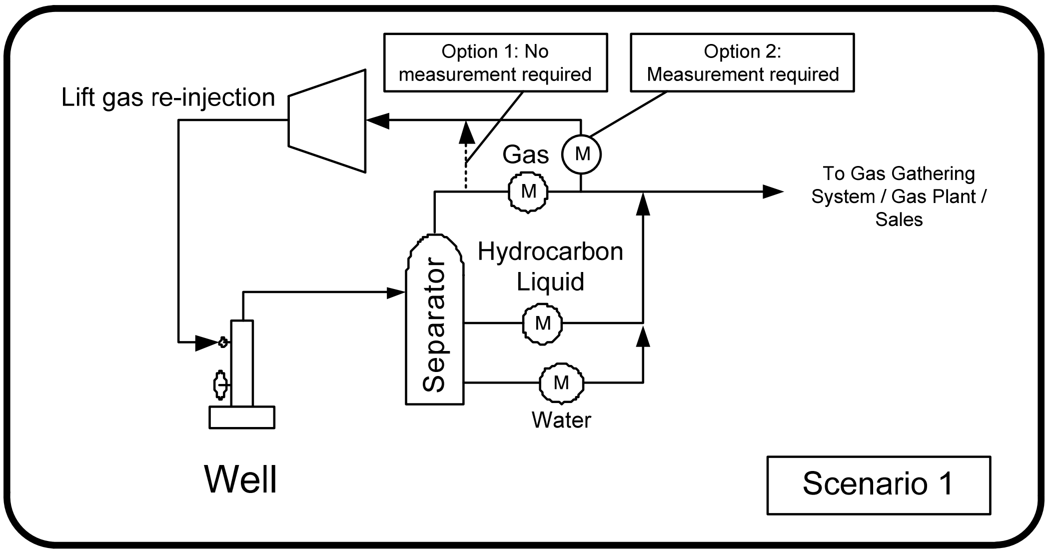
Gas plant condensate, C5+, and/or NGL sent to an oil battery must be measured and reported as disposition to the oil battery. This is a royalty trigger point requiring delivery point measurement.

#### 4.3.3.2 Gas Lift Systems for Both Oil and Gas Wells

There are four gas source scenarios, and each one may be subjected to different measurement, reporting, and sampling and analysis requirements when gas is injected into the wellbore to assist in lifting the liquids to the surface.

**Scenario 1**

There is no external gas source for the lift gas used; the raw gas is being separated and recirculated continuously at the well site with compressor(s). Regular sampling and analysis frequency for the well type applies (see Section 8.4).




**Option 1**: If the lift gas is taken from upstream of the production measurement point, then there is no reporting requirement.

**Option 2**: If the lift gas is taken from downstream of the production measurement point, then measurement of the lift gas is required and the total well gas production will be the difference between the total measured production volume and the measured lift gas volume.

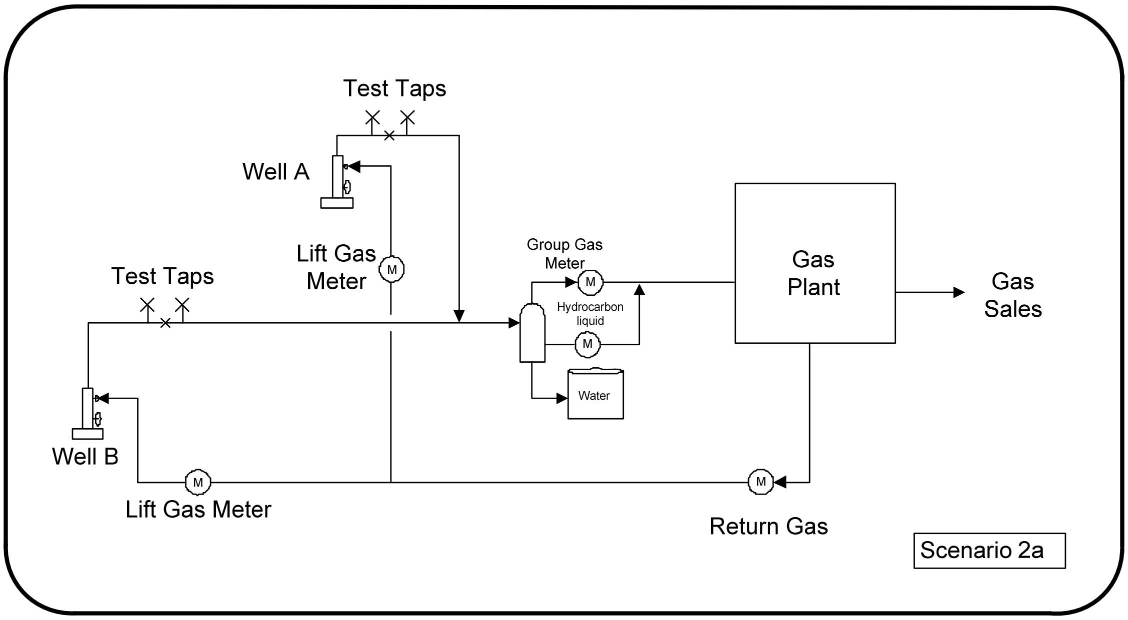
**Scenario 2**

The lift gas is received back from a downstream gas plant/facility that is classified as "return gas" (no royalty implications).

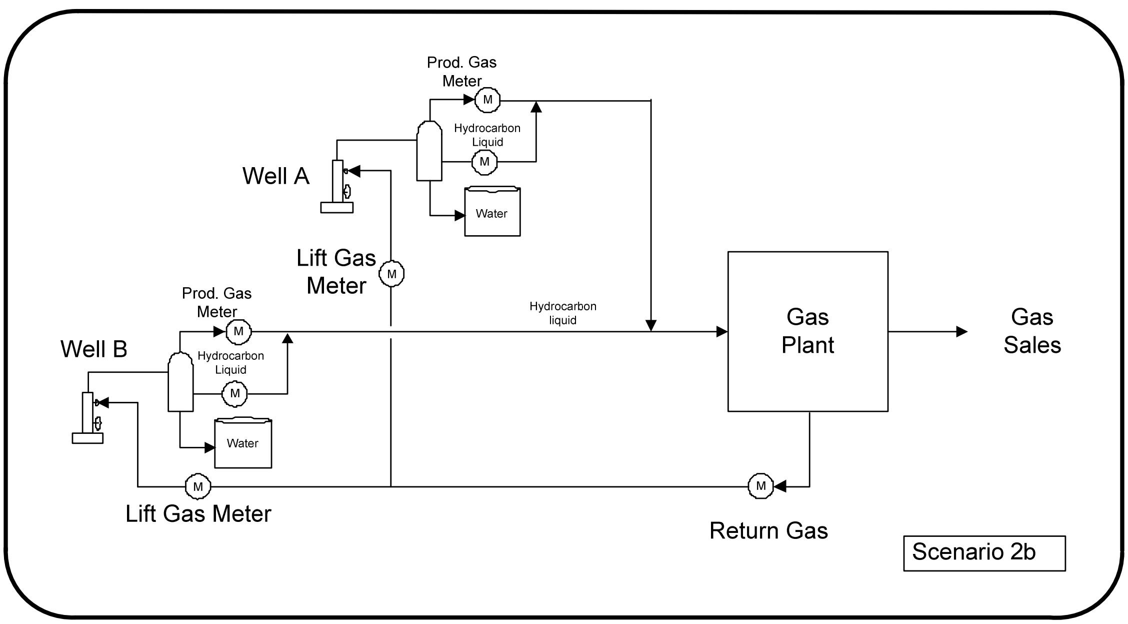
Measurement is required at the battery level for any gas coming back from the gas plant/facility after sweetening/processing and reported as "REC." Part of this return gas could be used for fuel at the well. The lift gas injected into the wellbore must be measured and regular sampling and analysis frequency for the well type applies (see Section 8.4).

There are two possibilities under scenario 2 (see below).

For proration tested wells, the gas lift volume during the test period must be netted off the total test gas production volume to determine the estimated gas production volume for each well.




For continuously measured wells, the gas lift volume must be netted off the total measured gas production volume to determine the actual gas production volume for each well.



### Scenario 3

The lift gas comes from external sources with royalty implications.

Any gas coming from a non-royalty paid gas source must be measured and reported at the battery/facility level as “PURREC” and as “PURDISP” at the sending facility. The well measurement and reporting requirement is the same as scenario 2 above and the gas sampling and analysis frequency for this type of gas lift well is semiannual.

### Scenario 4

The lift gas comes from royalty exempted sources, such as TCPL or ATCO Gas.

The measurement and reporting requirement is the same as scenario 2 with the additional requirement that prior approval must be obtained from Alberta Energy to use the royalty-paid stream ID# WG999999 for the SAF/OAF submission to identify royalty-exempted gas that is to be used as gas lift.

The PRA requirement is to update/change the well status of all wells that use gas lift. The gas sampling and analysis frequency for this type of gas lift well is semiannual.

## 7.4 Gas Multiwell Effluent Proration Batteries

The proposed revisions to Sections 7.4 and 7.4.1 are indicated in blue.

Gas wells in this type of battery have dedicated "effluent" or "wet gas" measurement, whereby total multiphase well fluid passes through a single meter (see Figure 7.7). This type of measurement must be subjected to testing regardless of the type of effluent meter used. For a new completion or recompletion of another zone in an existing well, effluent measurement is not allowed at a certain LGR level (see Section 7.4.1.1 for details).

**Definitions**

| | |
|---|---|
| "Near measured" production | Gas well production that qualifies for effluent metering but requires annual or biennial testing based on the regulatory effluent testing decision tree. Effluent correction factors are applied to the effluent measured gas production and used in determining a well's water-gas ratio (WGR) to determine water production volumes. |
| "Deemed dry" production | Applies to gas effluent wells that qualify for testing exemption based on the effluent testing decision tree. Includes wells that are categorized within a zone-based effluent testing exemption where the average liquid gas ratio (LGR) results of testing are less than 0.056 $m^3/10^3$ $m^3$. |
| "Measured" gas source | Production that is diverted through a separator and includes measurement of each phase (gas and liquid). |

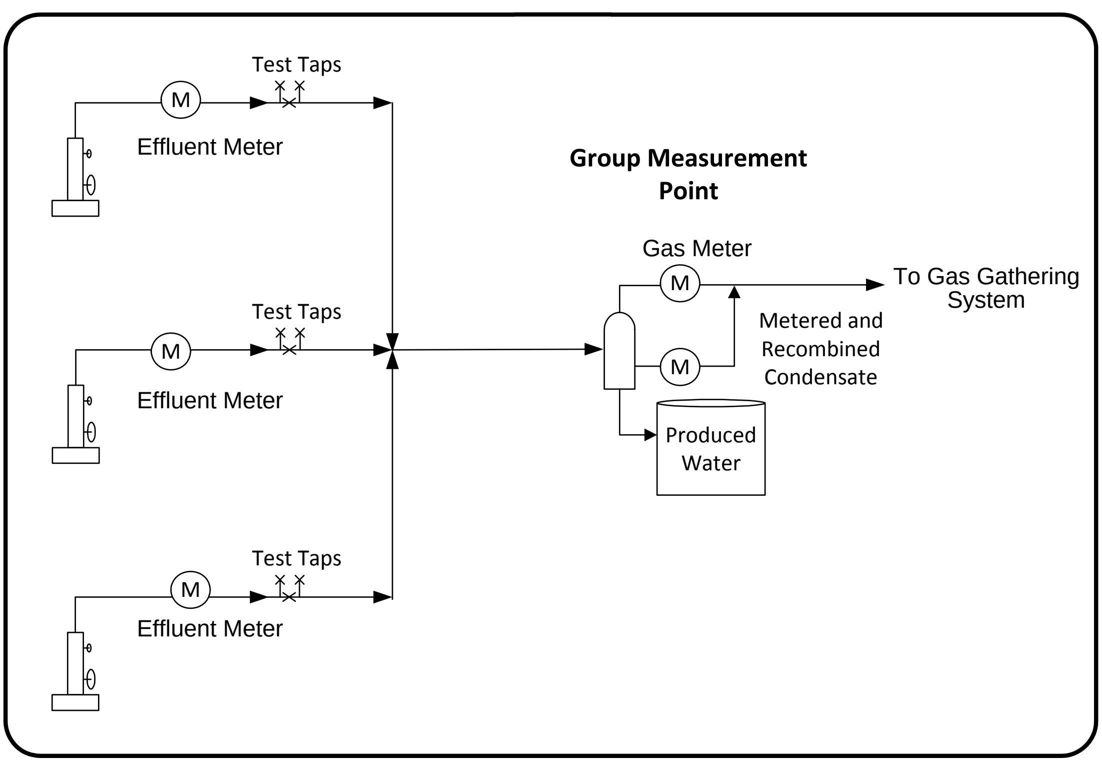



Figure 7.7. Typical multiwell effluent proration battery configuration

Production rates, WGR, CGR, and ECF determined during a well test must be used in the estimation/proration calculations within 60 days of the test until the next test is conducted.

Total battery gas production must be measured and prorated back to the individual wells, based on each well's estimated monthly gas production. Estimated well gas production is based on the total volume measured by the effluent meter multiplied by an ECF (see Figure 7.8). The uncertainty of measurement will increase with higher liquid rates, especially under liquid slugging conditions.

Figure 7.8 illustrates a typical gas well effluent measurement configuration. Production from the gas well passes through a line heater (optional), where it is heated. This is typically done to vapourize some of the hydrocarbon liquids and heat up the water and the gas in the stream before metering to prevent hydrate formation. For well testing purposes, test taps must be located downstream of this meter within the same pipe run. The line heater and/or the fuel gas tap, if present, must be upstream of the meter or downstream of the test taps to ensure that the test meter is subjected to the same condition as the effluent meter. After measurement, production from the well is commingled with other flow-lined effluent gas wells in the battery and sent to a group location, where single-phase (group) measurements of hydrocarbon liquids, gas, and water must be conducted downstream of separation.

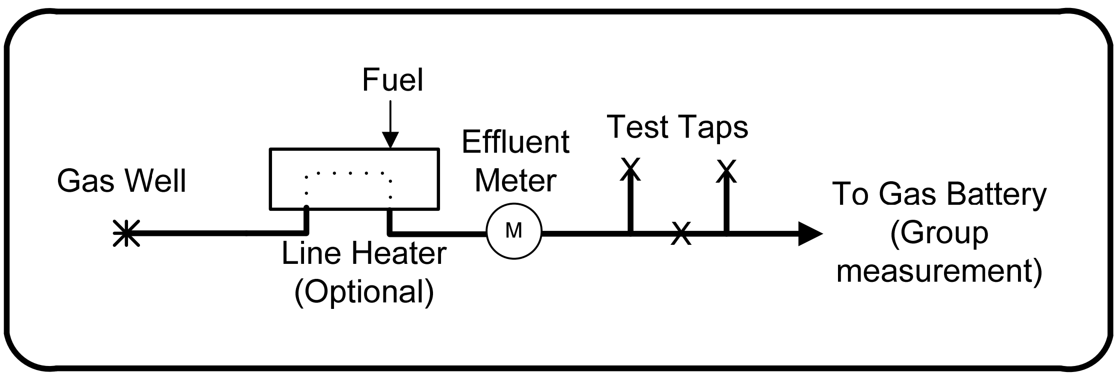



Figure 7.8. Typical gas well effluent metering configuration

For most wells, the required minimum well testing frequency is annual unless the criteria in Section 7.4.1.1 are met. Total battery water production must be measured and prorated back to the individual wells, based on each well's estimated monthly water production. Estimated well water production is based on a WGR, determined by periodic well tests multiplied by the estimated monthly well gas production.

Gas wells that are classified as producing oil, rather than condensate, must not be tied into an effluent proration battery, unless the well oil and gas production volumes are separated and measured prior to commingling with the effluent wells and either the "Exception" criteria in Section 5.5 are met or site-specific approval has been obtained from the ERCB prior to implementation.

If a gas well classified as producing condensate in a multiwell effluent proration battery is reclassified by the ERCB as producing oil, see Section 7.4.3.

### 7.4.1 Well Testing

Well testing is performed by directing well production downstream of the effluent meter and within the same pipe run through a three-phase portable test separator configured with dedicated meters for gas, condensate, and water (see Figure 7.9). Test equipment using two-phase separation is acceptable if hydrocarbon liquids are too small to be measured during typical well test durations. Other options that provide equivalent liquid volume determination accuracy may also be considered. For example, if a three-phase separator is not available, alternative equipment, such as a two-phase separator with a total liquid meter and continuous water cut analyzer, may be acceptable. The test must be conducted as follows:

The test must begin only after a liquid level stabilization period within the test separator.

The test duration must be a minimum of 12 hours.

The required minimum well testing frequency is annual unless the criteria specified in Section 5.7 are met. All new wells must be tested within the first 30 days of initial production.

Consistent testing procedures must be used for consecutive tests to identify if a change in a well's flow characteristics has occurred.

The gas, condensate, and water volumes must be measured.

The condensate must be sampled during every test and subjected to a compositional analysis, which is to be used to determine the GEF. The sample may be taken from the condensate leg of a three-phase separator or the liquid leg of a two-phase separator (the water must be removed from the condensate before conducting the analysis).

The GEF must be used to convert the liquid condensate volume determined during the test to a GEV, which will be added to the measured test gas volume to determine the total test gas volume if the condensate is not delivered for sale at the group measurement point (see Section 7.4.2).

The WGR must be determined by dividing the test water volume by the sum of the measured test gas volume and the gas equivalent of the measured test condensate volume if the condensate is not delivered for sale at the group measurement point (see Section 7.4.2).

The ECF must be determined by dividing the sum of the measured test gas volume and the GEV of the measured test condensate volume by the effluent metered gas volume.

For orifice meters, the effluent meter and the test gas meter must use 24-hour charts for a test period of 24 hours or less, unless electronic flow measurement is used; for testing periods longer than 24 hours, 7-day charts may be used, provided that good, readable pen traces are maintained (see Section 4.3.4).

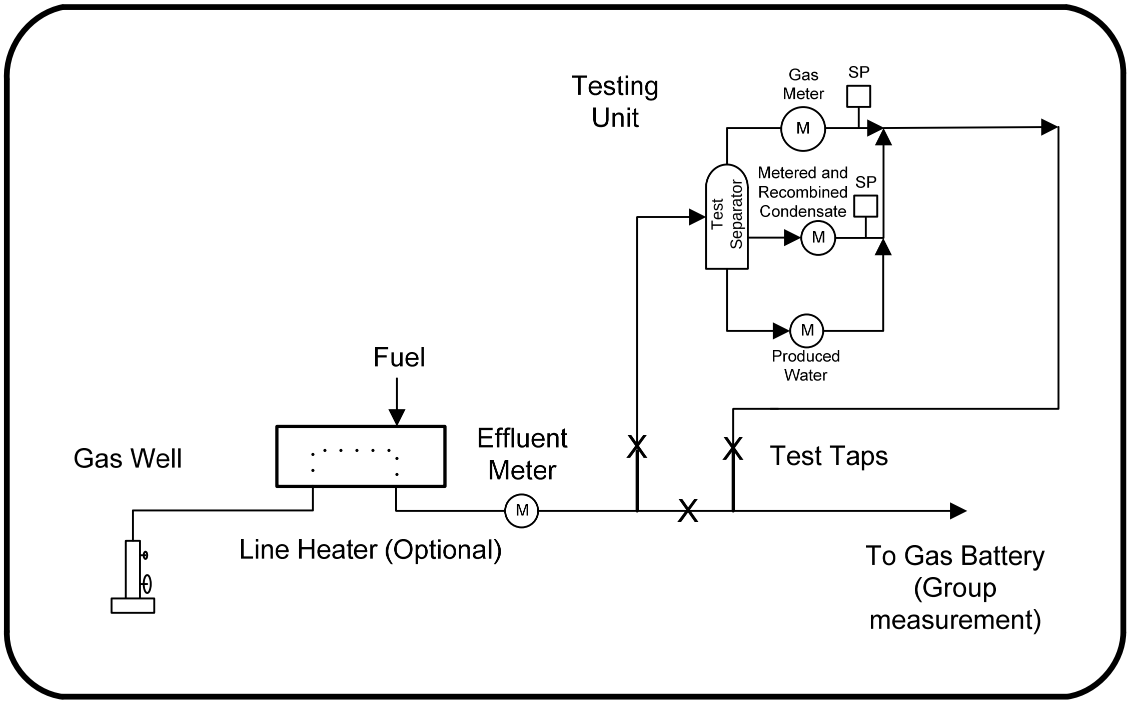



Figure 7.9. Typical effluent well measurement configuration with test unit

#### 7.4.1.1 Well Measurement and Testing Decision Tree

The type of measurement and testing frequency for wet measured wells must follow the decision tree process in Figure 7.10.

Note that the starting point for initial well completion or recompletion is different than for existing effluent zones/wells.

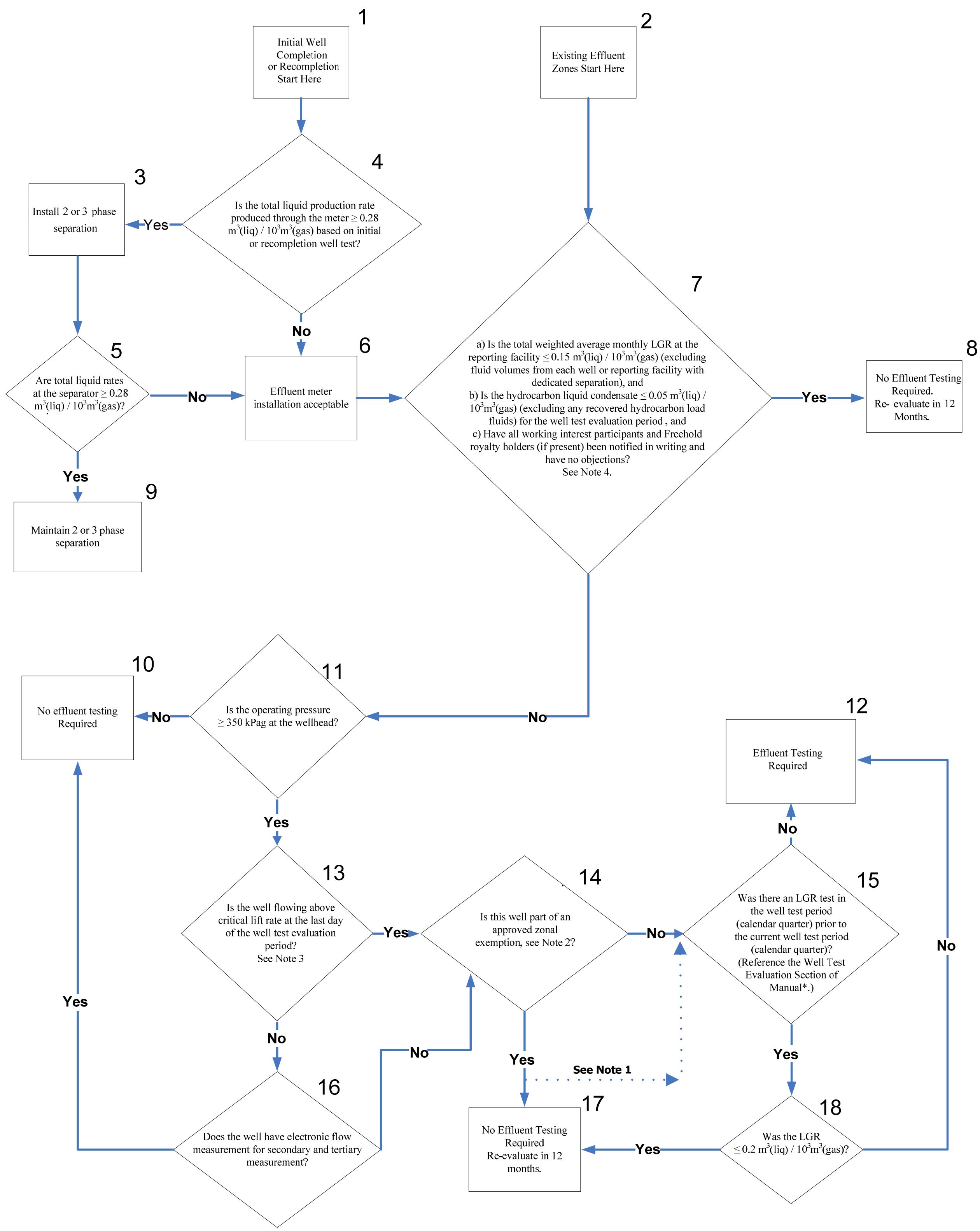



Figure 7.10. Well measurement and testing decision tree

Note 1: Where all wells in a facility are above critical lift and in a deemed exempted zone, if the LGR is greater than 0.2 $m^3$ (l)/$10^3$ $m^3$ (g) at the respective facility inlet to which the wells flow, the zone is not exempted and the Note 1 path is to be followed.

Note 2: *ERCB* zonal measurement exemptions are by special approvals only.

Note 3: The Turner Correlation[1] is used to approximate critical lift. The calculation below produces a value in million standard cubic feet (mmscf) per day. Use a factor of 28.3168 $10^3$ $m^3$/mmscf to convert to metric units. Although there have been further refinements to the Turner Correlation calculation, the formulas below will be applied to determine critical lift as it is relates to the well measurement and testing decision tree. These simplified formulas assume a fixed-gas gravity (G) of 0.6 and fixed-gas temperature (T) of 120ºF.

$$v_g(Water) = \frac{5.62(67 - kP)^{0.25}}{(kP)^{0.50}}$$

$$v_g(Condensate) = \frac{4.02(45 - kP)^{0.25}}{(kP)^{0.50}}$$

$$k = \frac{2.693G}{ZT}$$

$$q_g = \frac{3.06 P v_g A}{ZT}$$

G = gas gravity
P = Pressure (absolute) - lb force / square inch
T = Temperature (absolute) – degrees Rankine
Vg = Minimum gas velocity required to lift liquids – ft / second
Z = Compressibility factor
A = Cross sectional area of flow – square feet
Qg = Flow rate – mmscf / day

The following represents a sample Turner Correlation calculation:

Evaluation period: November – October
SCADA daily average tubing pressure, October: 684.6 kPa
Turner Correlation formula: assumes G = 0.6
T = 48.9ºC (120ºF)
Z = 0.9

| Variable | Value | Units | Calculation |
|---|---|---|---|
| G | 0.6 | | |
| z | 0.9 | | |
| T | 580 | Rankin | [(48.9 x 1.8) + 32] + 460 |
| k | .003095 | | (2.693 x 0.6)/(0.9 x 580) |
| P | 114 | PSIA | (684.6 kPa / 6.89475) + (101.325 kPa / 6.89475) |
| A | .0217 | $Ft^2$ | [3.1415 x (1.995 inches/12)$^2$]/4 (Tubing size = 2 3/8 inches) |
| Qg | 0.392 | mmscf/d | |
| Qg | 11.10 | $10^3$ $m^3$/d | 0.392 mmscf x 28.3168 $10^3$ $m^3$ / mmscf |

If both condensate and water are present, use the Turner Correlation for water to evaluate system behavior. The Turner Correlation uses the cross-sectional area of the flow path when calculating liquid lift rates. For example, if the flow path is through the tubing, the minimum

[1] Turner, R. G., Hubbard, M. G., and Dukler, A. E., 1969, "Analysis and Prediction of Minimum Flow Rate for the Continuous Removal of Liquids from Gas Wells," *JPT* 21(11): 1475–1482.

gas rate to lift water and condensate is calculated using the tubing inside diameter. When the tubing depth is higher in the wellbore than the midpoint of perforations (MPP) in a vertical well, the Turner Correlation does not consider the rate required to lift liquids between the MPP and the end of the tubing. Ultimately, the liquid lift rate calculations are based on the inside diameter (ID) of the tubing or the area of the annulus and not on the casing ID unless flow is up the casing only.

Note 4: Average Monthly LGR/CGR Calculation

Follow the well measurement and testing decision tree (Figure 7.10) to determine if a facility exemption is appropriate for specific wells that flow to the reporting facility based on the total liquid/condensate volumes versus the total gas volume measured at the group measurement for the reporting month. Production volumes include not only volumes measured at a group measurement point, but all fluid production volumes used for reporting purposes. This requires accounting for all fluid volumes that are received into or delivered out of the reporting facility for that reporting month.

LGR = [Total group measured liquids (condensate + water) + (Disposition + Inventory change before group measurement) – Liquid received] / [Total group measured gas + (fuel + flare + vent before group measurement) + Disposition before group gas measurement – Gas received]

CGR = [Total group measured condensate + (Disposition + Inventory change before group measurement) – Condensate received] / [Total group measured gas + (fuel + flare + vent before group measurement) + Disposition before group gas measurement – Gas received]

#### 7.4.1.2 Well Test Evaluation

The well testing evaluation period is based on a cycle of 12 consecutive months that all of the wells in a reporting facility will identically follow. The well test evaluation period must end two months before the planned calendar quarter in which the required well testing will be conducted for a reporting facility. Once the evaluation period is chosen, it will remain fixed for a reporting facility. Well testing, when required, must occur once in a fixed calendar quarter period and once within a four consecutive calendar quarter period. Figure 7.11 provides an illustrated example.

Well and reporting facility data are gathered for the 12-month period identified. The wells and/or the reporting facility would be analyzed within the context of the well measurement and testing decision tree. Initializing the design will establish the cycle that is repeated year over year. The operator is free to choose the well testing calendar quarter based on operations. The illustrated example may typically fit a well testing system in which winter road access is available.

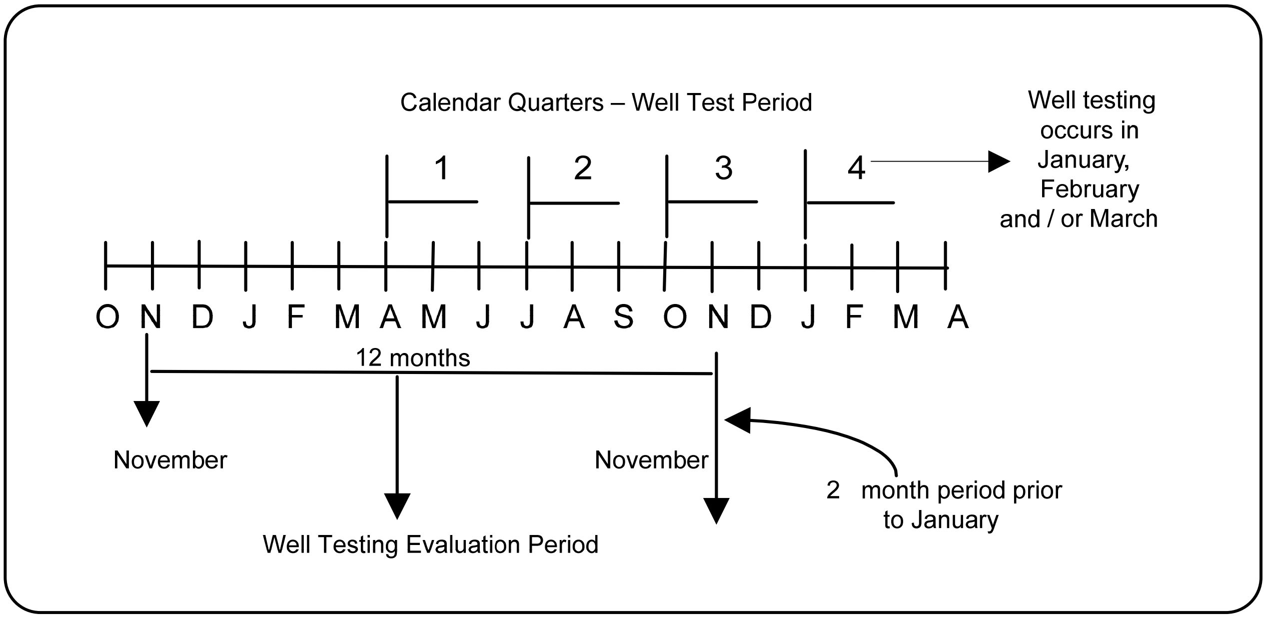



Figure 7.11. Well test evaluation example

For the purposes of evaluating text box 7 of the well measurement and testing decision tree, the reporting facility and the affected wells (i.e., wells without well separation) will be on the same well testing evaluation period. If, however, a reporting facility has operating characteristics such that a reporting facility well testing exemption (text box 7) is not possible, the well testing evaluation period can become unique to a well. This means that for a well that requires testing according to the well measurement and testing decision tree, the well maintains a codified well testing evaluation period, but the well testing evaluation period may not be the same for all of the wells in a reporting facility. If a facility is of such a size that it would take more than one calendar quarter to test all of the wells, an operator can choose the calendar quarter in which a well test is to occur which in turn determines the Well Testing Evaluation Period. Once the well testing period (calendar quarter) is chosen, the operator must test once in the fixed calendar quarter period and the well test must occur once within a four consecutive calendar quarter period.

The pressure data, as recorded by the well site measurement equipment, will be the monthly average for the last month of the well test evaluation period. If no tubing or casing pressure records are continuously recorded, then the upstream static pressure data from the well's flow meter may be used to approximate the tubing or casing pressure provided that the well's flow meter is located on the same lease site as the wellhead.

#### 7.4.1.3 Record Keeping

The following lists the minimum records required related to well testing and/or the well measurement and testing decision tree:

1) Producer
2) Reporting facility – name and surface location
3) Well - name
4) Well - unique well identifier (UWI)
5) Production formation(s) – name(s) and/or zone codes(s)
6) Current well testing date
7) Last well test date
8) Effluent well meter run - internal diameter (mm)
9) Meter run orifice size (mm) (if applicable)
10) Test tap location (relative to effluent meter)
11) Test tap connection – diameter (mm)
12) Last gas sample date
13) Last condensate sample date
14) Wellhead tubing internal diameter (mm)
15) Wellhead casing internal diameter (mm)
16) Wellhead tubing pressure (KPa)
17) Wellhead casing pressure (KPa)
18) Effluent meter monthly average D/P for evaluation period (kPa) – listed by month
19) Effluent meter monthly average static pressure for evaluation period (KPa) – listed by month
20) Effluent meter monthly average temperature for evaluation period (ºC) – listed by month
21) Test gas rate ($10^3$ $m^3$/day)
22) Test condensate rate ($m^3$/day)
23) Test water rate ($m^3$/day)
24) Current WGR ($m^3/10^3$ $m^3$)
25) Current CGR ($m^3/10^3$ $m^3$)
26) Current LGR ($m^3/10^3$ $m^3$)
27) Last WGR ($m^3/10^3$ $m^3$)
28) Last CGR ($m^3/10^3$ $m^3$)
29) Last LGR ($m^3/10^3$ $m^3$)
30) ECF – last value calculated
31) ECF – current value calculated
32) Evaluation period average reporting facility LGR
33) Evaluation period average reporting facility CGR
34) Artificial lift method (i.e., cycling, plunger control)
35) Well EFM – model and make or not applicable
36) Well chart – yes / no
37) Well test evaluation period starting month
38) Well test evaluation period ending month

39) Date well dropped below critical velocity
40) Critical lift calculation for evaluation period
41) Well load fluid volumes for evaluation period
42) Meters used in facility LGR calculations
    a) Meter tag
    b) Meter location
    c) Meter volume
    d) Meter units ($10^3$ $m^3$, etc.)
43) Well flow volume prior to recompletion
44) Well recompletion flow volume

#### 7.4.1.4 Revocation of Exemption

Below are the criteria under which an effluent gas well testing exemption may be revoked. At a minimum, baseline well testing for the wells included in an exemption decision must be implemented if any of the following occurs:

1) Noncompliance. Potential areas of noncompliance include the following:
    a) Incorrect exemption calculations.
    b) Inadequate recordkeeping.
    c) Source data for exemption calculations cannot be validated.
    d) Incorrect application/implementation of the well measurement and testing decision tree.

2) All working interest participants and Freehold royalty holders (if present) were notified in writing and a working interest participant or Freehold royalty holder for any flowing well to the reporting facility objects to the exemption.

Additionally, if the ERCB has a concern with respect to the activities, operations, production data, or reporting associated with well testing and/or well testing activities, upon notice in writing, the ERCB can partially or fully revoke well testing exemptions and impose, modify, or substitute well testing conditions for any period of time. The ERCB will advise the operator in writing as to the reason for the revocation, provide a reasonable period of time for the operator to meet the conditions set by the ERCB, as well as provide an opportunity for the operator to comment.

## Appendix 9 Schematic Example

The example on the following page is for information purposes only. An operator may use other symbols, letters, or words as long as it is clear in the legend or in the schematic what they stand for.

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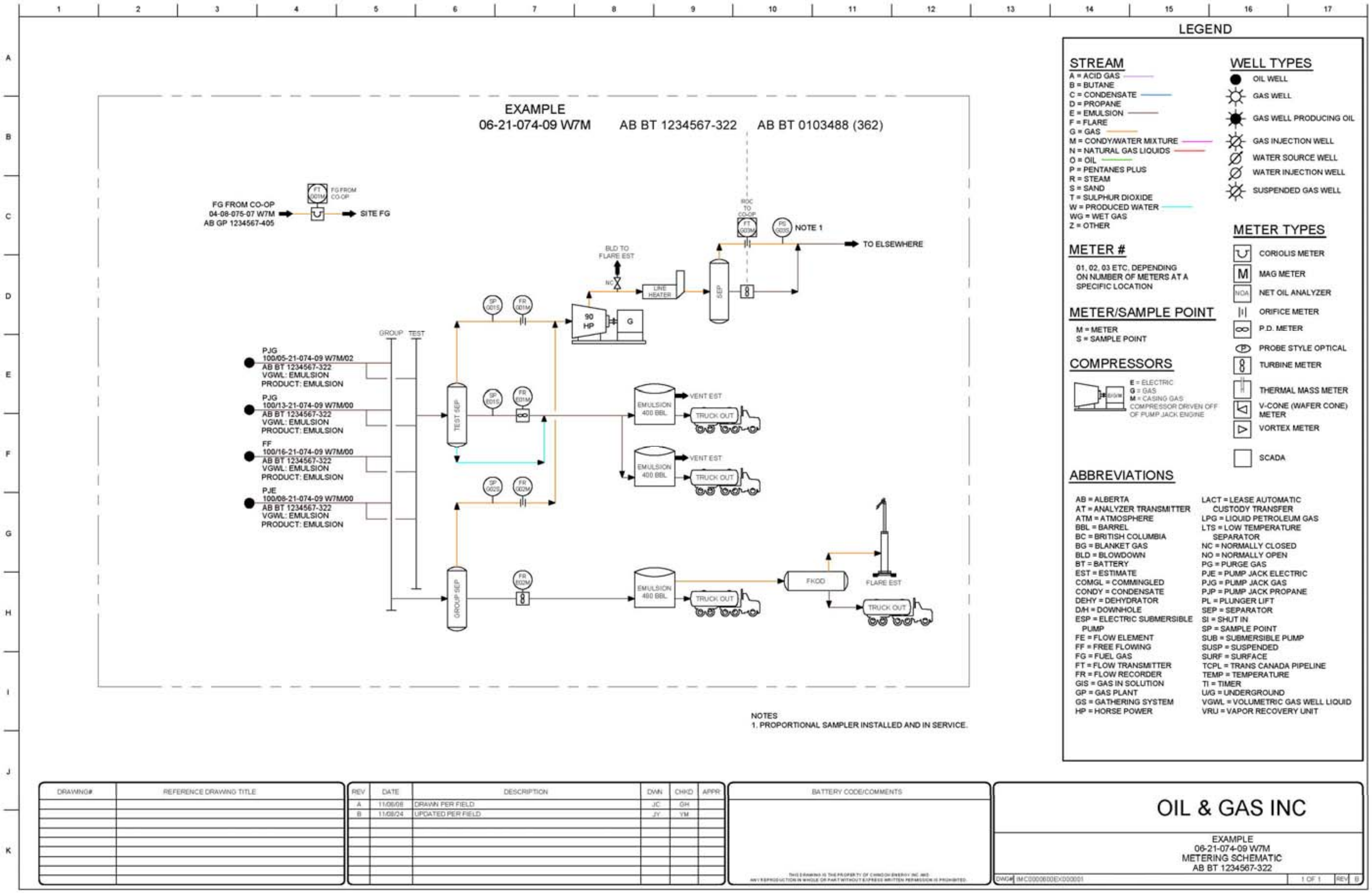
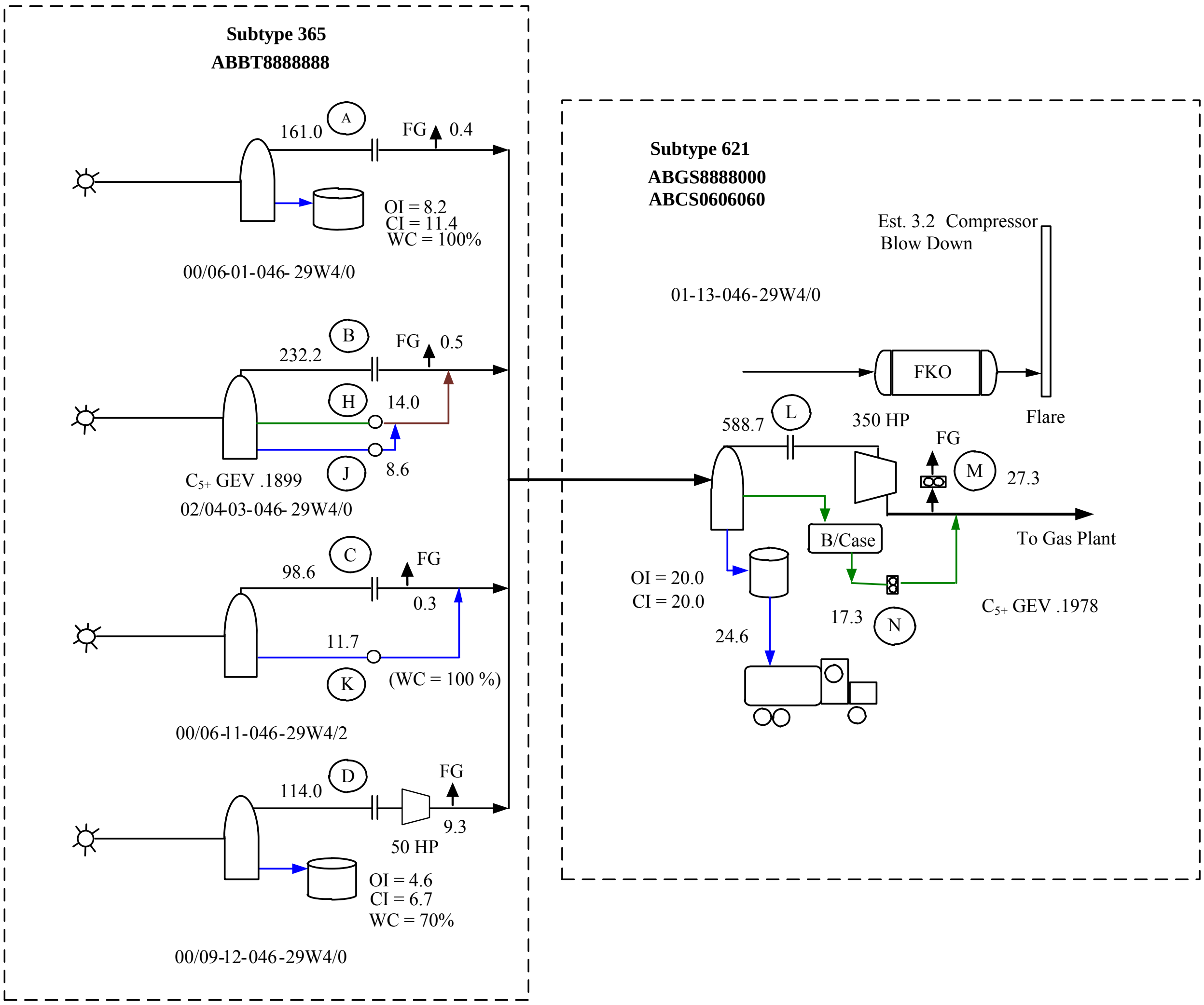


LEGEND
STREAM
A = ACID GAS
B = BUTANE
C = CONDENSATE
D = PROPANE
E = EMULSION
F = FLARE
G = GAS
M = CONDY/WATER MIXTURE
N = NATURAL GAS LIQUIDS
O = OIL
P = PENTANES PLUS
R = STEAM
S = SAND
T = SULPHUR DIOXIDE
W = PRODUCED WATER
WG = WET GAS
Z = OTHER
METER #
01, 02, 03 ETC. DEPENDING ON NUMBER OF METERS AT A SPECIFIC LOCATION
METER/SAMPLE POINT
M = METER
S = SAMPLE POINT
COMPRESSORS
E = ELECTRIC
G = GAS
M = CASING GAS COMPRESSOR DRIVEN OFF OF PUMP JACK ENGINE
WELL TYPES
OIL WELL
GAS WELL
GAS WELL PRODUCING OIL
GAS INJECTION WELL
WATER SOURCE WELL
WATER INJECTION WELL
SUSPENDED GAS WELL
METER TYPES
CORIOLIS METER
MAG METER
NET OIL ANALYZER
ORIFICE METER
P.D. METER
PROBE STYLE OPTICAL
TURBINE METER
THERMAL MASS METER
V-CONE (WAFER CONE) METER
VORTEX METER
SCADA
ABBREVIATIONS
AB = ALBERTA
AT = ANALYZER TRANSMITTER
ATM = ATMOSPHERE
BBL = BARREL
BC = BRITISH COLUMBIA
BG = BLANKET GAS
BLD = BLOWDOWN
BT = BATTERY
EST = ESTIMATE
COMGL = COMMINGLED
CONDY = CONDENSATE
DEHY = DEHYDRATOR
D/H = DOWNHOLE
ESP = ELECTRIC SUBMERSIBLE PUMP
FE = FLOW ELEMENT
FF = FREE FLOWING
FG = FUEL GAS
FT = FLOW TRANSMITTER
FR = FLOW RECORDER
GIS = GAS IN SOLUTION
GP = GAS PLANT
GS = GATHERING SYSTEM
HP = HORSE POWER
LACT = LEASE AUTOMATIC CUSTODY TRANSFER
LPG = LIQUID PETROLEUM GAS
LTS = LOW TEMPERATURE SEPARATOR
NC = NORMALLY CLOSED
NO = NORMALLY OPEN
PG = PURGE GAS
PJE = PUMP JACK ELECTRIC
PJG = PUMP JACK GAS
PJP = PUMP JACK PROPANE
PL = PLUNGER LIFT
SEP = SEPARATOR
SI = SHUT IN
SP = SAMPLE POINT
SUB = SUBMERSIBLE PUMP
SUSP = SUSPENDED
SURF = SURFACE
TCPL = TRANS CANADA PIPELINE
TEMP = TEMPERATURE
TI = TIMER
U/G = UNDERGROUND
VGWL = VOLUMETRIC GAS WELL LIQUID
VRU = VAPOR RECOVERY UNIT
EXAMPLE
06-21-074-09 W7M
AB BT 1234567-322
AB BT 0103488 (362)
FG FROM CO-OP
04-08-075-07 W7M
AB GP 1234567-405
SITE FG
NOTE 1
TO ELSEWHERE
BLD TO FLARE EST
LINE HEATER
SEP
90 HP
G
GROUP
TEST
PJG
100/05-21-074-09 W7M/02
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
PJG
100/13-21-074-09 W7M/00
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
FF
100/16-21-074-09 W7M/00
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
PJE
100/08-21-074-09 W7M/00
AB BT 1234567-322
VGWL: EMULSION
PRODUCT: EMULSION
TEST SEP
GROUP SEP
EMULSION 400 BBL
VENT EST
TRUCK OUT
FKOD
FLARE EST
NOTES
1. PROPORTIONAL SAMPLER INSTALLED AND IN SERVICE.
DRAWING#
REFERENCE DRAWING TITLE
REV
DATE
DESCRIPTION
DWN
CHKD
APPR
A
11/08/08
DRAWN PER FIELD
JC
GH
B
11/08/24
UPDATED PER FIELD
JY
YM
BATTERY CODE/COMMENTS
OIL & GAS INC
EXAMPLE
06-21-074-09 W7M
METERING SCHEMATIC
AB BT 1234567-322
1 OF 1

## Appendix 10 Gas Group Delineation

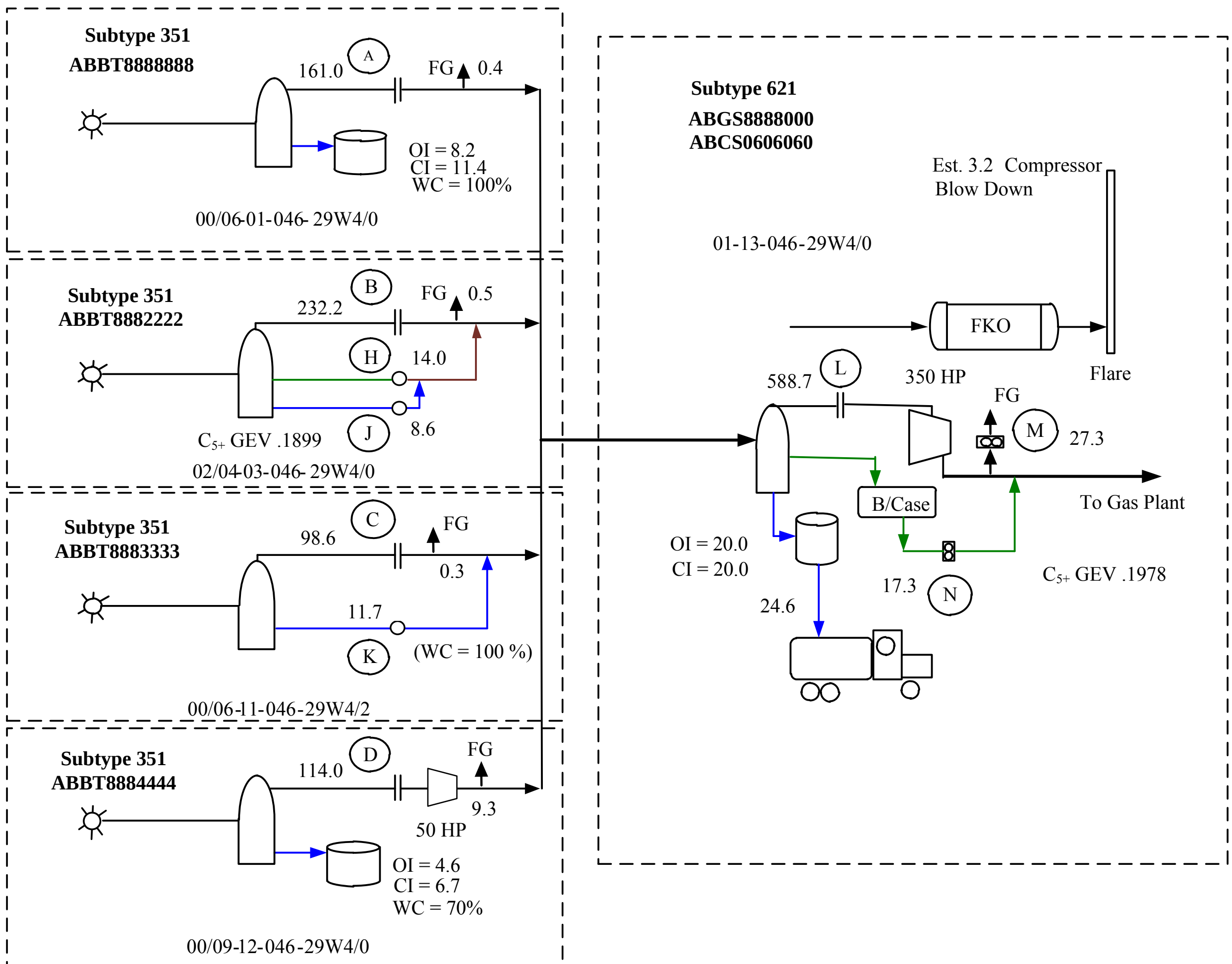
### Case 1[1, 2]




ABBT8888888 Gas Production = 161.0 + 232.2 (0.1899 x 14.0) + 98.6 + 114.0 = 608.5
ABBT8888888 Gas Delivered = 608.5 − (0.4 + 0.5 + 0.3 + 9.3) = 598.0
ABBT8888888 Water Production = 3.2 + 8.6 + 11.7 + [(6.7 − 4.6) x 0.7] = 25.0
ABBT8888888 Oil Production = [(6.7 – 4.6) x 0.3] = 0.6
ABGS8888000 Receipts = 598.0
ABGS8888000 Gas Delivered = 588.7 – 27.3 + (0.1978 x 17.3) – 3.2 = 561.6
ABGS8888000 MD = 598.0 – 592.1= 5.9 (1.0%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

**Case 2**[1, 2]




ABBT8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.6
ABBT8888888 Water Production = 3.2
ABBT8882222 Gas Production = 232.2 + (14 x 0.1899) = 234.9; Delivered = 234.9 – 0.5 = 234.4
ABBT8882222 Water Production = 8.6
ABBT8883333 Gas Production = 98.6; Delivered = 98.6 – 0.3 = 98.3
ABBT8883333 Water Production = 11.7
ABBT8884444 Gas Production = 114.0; Delivered = 114 – 23.7 = 90.3
ABBT8884444 Water Production = (6.7 – 4.6) x 0.7 = 1.5
ABBT8884444 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABGS8888000 Gas Receipts = 160.6 + 234.4 + 98.3 + 90.3 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

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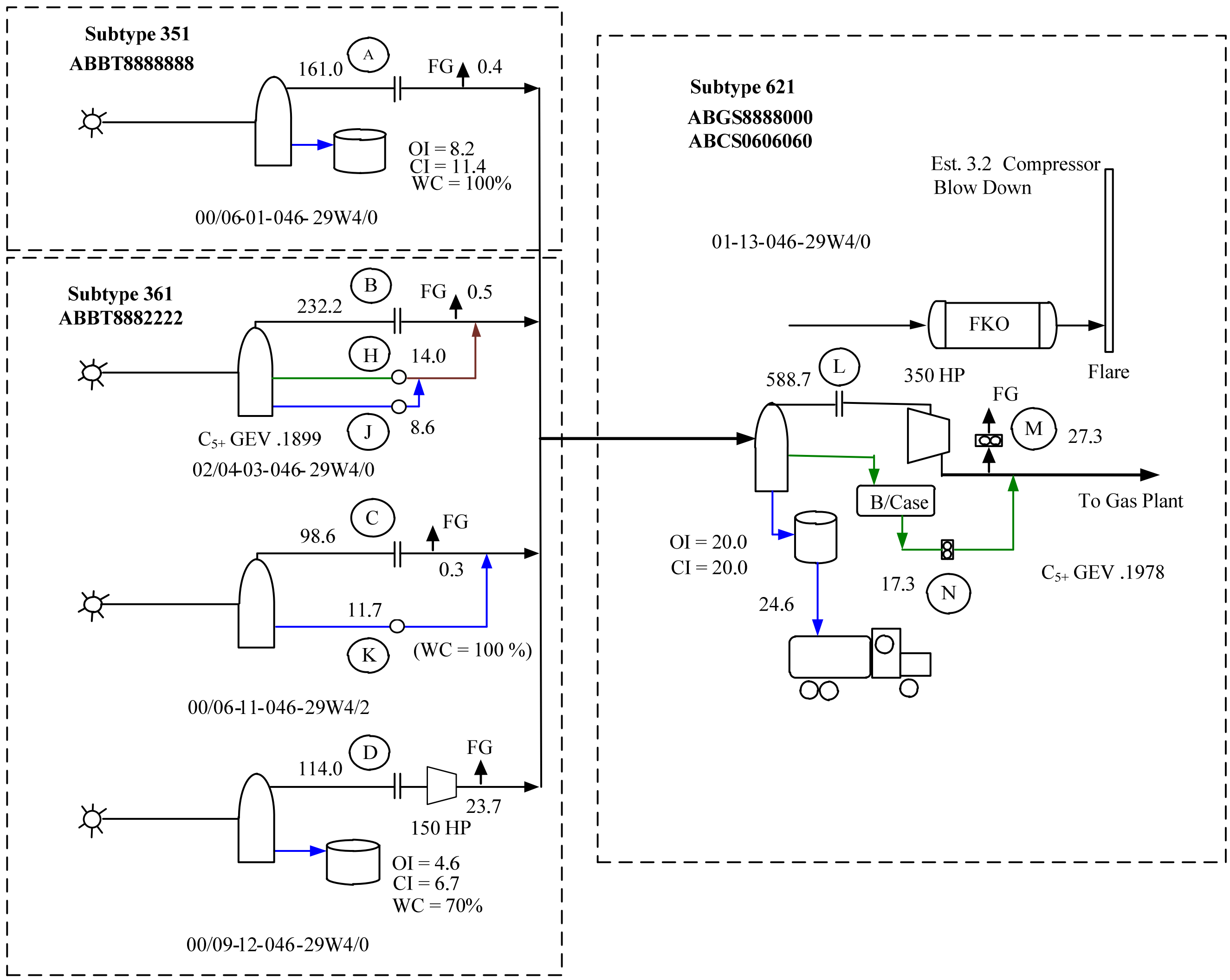
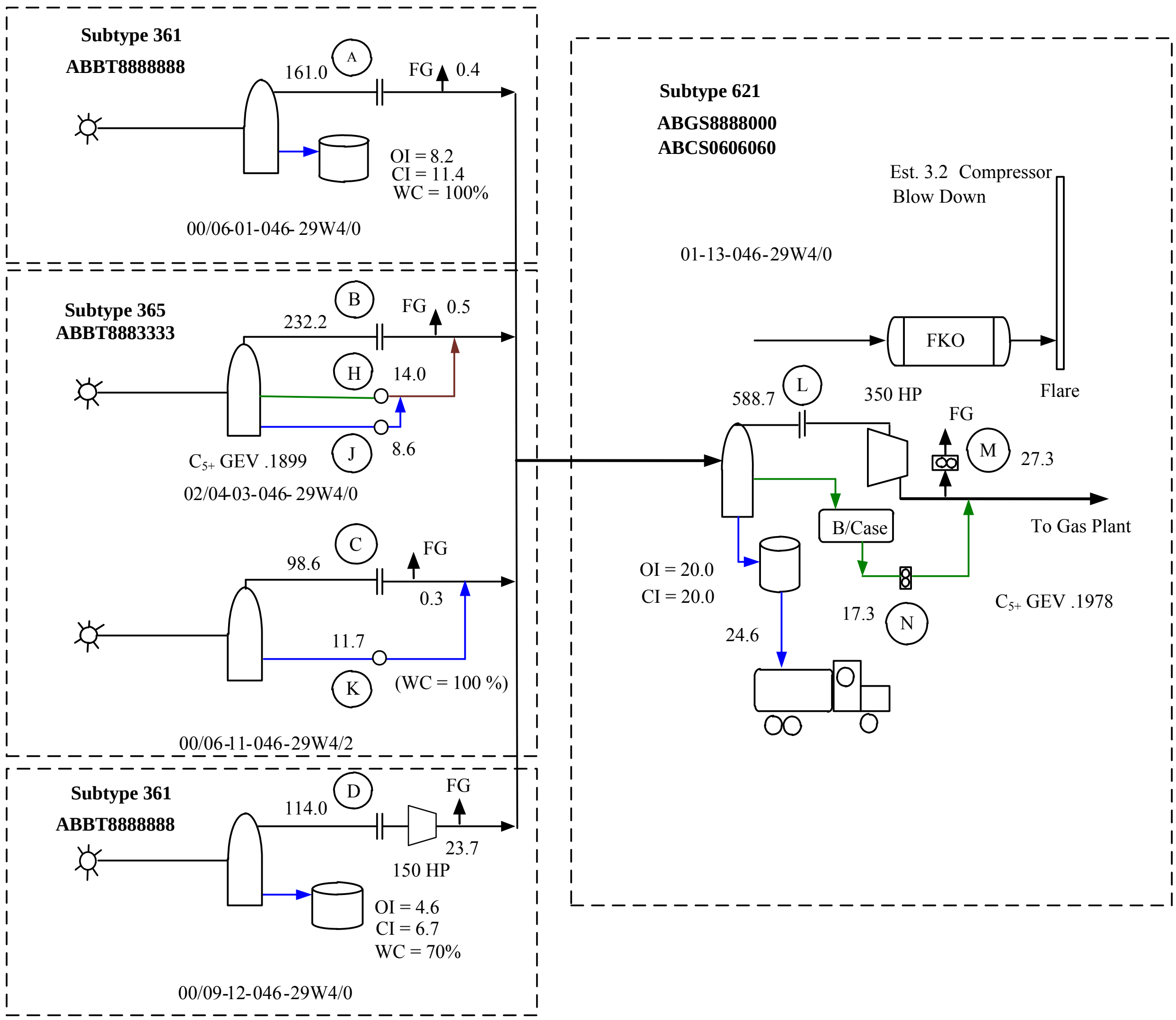
**Case 3**[1, 2]




| |
|---|
| ABBT8888888 Gas Production = 161.0; Delivered = 161.0 – 0.4 = 160.7 |
| ABBT8888888 Water Production = 3.2 |
| ABBT8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 + 114 = 447.5; Delivered = 447.5 – 24.5 = 423.0 |
| ABBT8883333 Water Production = 8.6 + 11.7 + [(6.7 – 4.6) x 0.7] = 21.8 |
| ABBT8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6 |
| ABGS8888000 Receipts = 423.0 + 160.6 = 583.6 |
| ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2 |
| ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%) |
| ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6 |
| ABWC Water Receipt = 24.6 – 20.3 = 4.3 |

[1] All wells sweet
[2] All volumes monthly

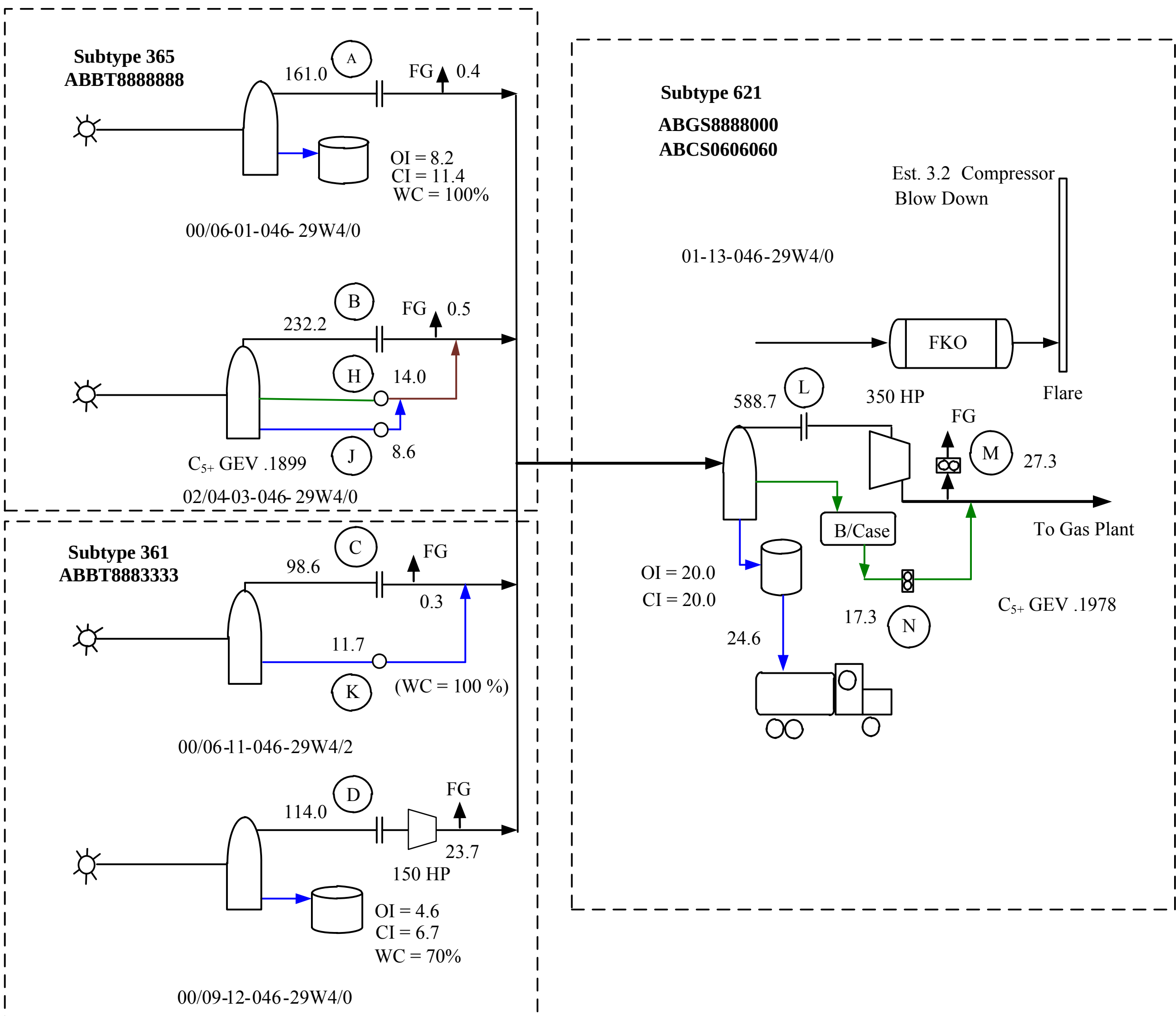
## Case 4[1, 2]




ABBT8888888 Gas Production = 161.0 + 114.0 = 275.0; Delivered = 275 – 0.4 – 23.7 = 250.9
ABBT8888888 Water Production = (11.4 – 8.2) + [(6.7 – 4.6) x 0.7] = 4.7
ABBT8888888 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABBT8883333 Gas Production = 232.2 + (14 x 0.1899) + 98.6 = 333.5; Delivered = 333.5 – 0.5 – 0.3 = 332.7
ABBT8883333 Water Production = 8.6 + 11.7 = 20.3
ABGS8888000 Receipts = 250.9 + 332.7 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly

## Case 5[1, 2]




ABBT8888888 Gas Production = 161.0 + 232.2 + (14 x 0.1899) = 395.9; Delivered = 395.9 – 0.4 – 0.5 = 395.0
ABBT8888888 Water Production = (11.4 – 8.2) + 8.6 = 11.8
ABBT8883333 Gas Production = 98.6 + 114 = 212.6; Delivered = 212.6 – 24 = 188.6
ABBT8883333 Water Production = 11.7 + [(6.7 – 4.6) x 0.7] = 13.2
ABBT8883333 Oil Production = (6.7 – 4.6) x 0.3 = 0.6
ABGS8888000 Receipts = 395 + 188.6 = 583.6
ABGS8888000 Gas Delivered = 566.3 – 27.3 + (0.1978 x 17.3) – 3.2 = 539.2
ABGS8888000 MD = 583.6 – 569.7 = 13.9 (2.4%)
ABGS8888000 Water Receipts = 8.6 + 11.7 = 20.3; Delivered = 24.6
ABWC Water Receipt = 24.6 – 20.3 = 4.3

[1] All wells sweet
[2] All volumes monthly